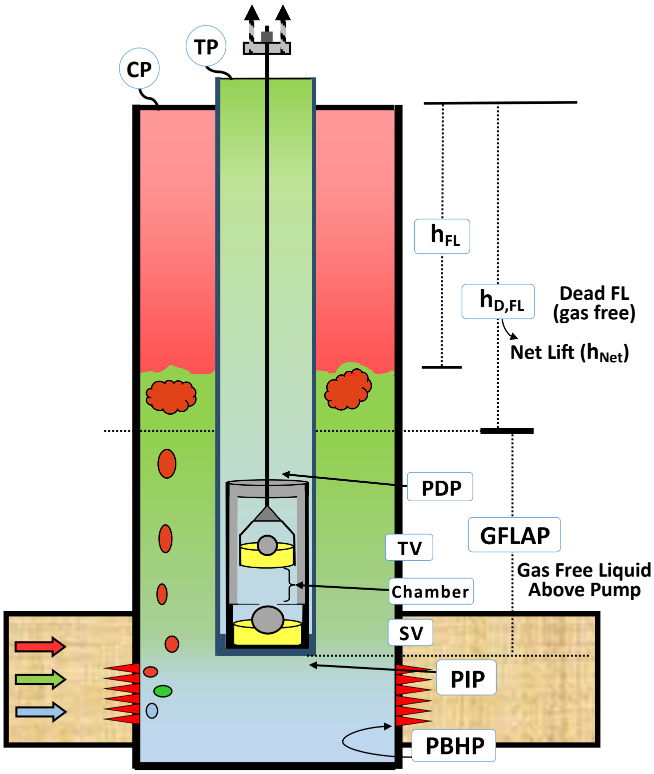


Note: Nomenclature table with units for all figures & equations given on the last page.

Calculated Production:

$$BFPD = 0.1166 \times d_p^{\,2} \times SPM \times SL_{DH} \times \varepsilon_p \times \%_{RT}$$

or

$$BFPD = C_p \times SPM \times SL_{DH} \times \varepsilon_p \times \%_{RT}$$

- ε_P: ≈ 0.85 for moderate wear/slippage.
- C_P: Pump Constant →

Pump	C_P
1-1/16"	0.132
1-1/4"	0.182
1-1/2"	0.262
1-3/4"	0.357
2"	0.466
2-1/4"	0.590

Downhole Pump Operation:

- Up-Stroke: the PIP charges the pump chamber full of fluid.
- Down-Stroke: the TV does not open (and thus no net fluid moved) *until* the fluid in the Pump Chamber is compressed to a pressure **>PDP**.
- Due to its compressible nature, free gas in the pump requires the plunger to travel much further into the down-stk before the gas becomes *compressed* enough (>PDP) for the TV to open. Additionally, as the plunger rises at the start of the up-stk the free gas *expands* to fill the new chamber volume created by the vacating plunger. This prevents the pressure in the chamber from rapidly dropping & necessitates the plunger travel further before **$P_{Chamber}$ < PIP** (so the SV will open to admit new fluid into the pump). → [see *Gas Int*. card next page]

Fluid Load on Pump (F_O) & Pump Intake/Displacement P. (PIP/PDP):

$$F_O = \left(A \times \Delta P\right)_{Pgr} = \frac{\pi}{4} d_P^{\,2} \times (PDP - PIP)$$

$$PIP = CP\left(1 + \frac{h_{D,FL}}{40{,}000}\right) + 0.433 \times SG_O \times GFLAP$$

$$PDP = TP + 0.433 \times SG_{O/W} \times h_{SN}$$

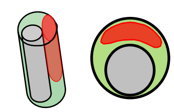
Note:

1) Only use TVD depths with hydrostatic calculations (if well is not vertical).
2) In steady-state production, *only* oil (no water) resides above the pump in the annulus.
3) For a pumped off well, as the SN depth increases the ΔP_{Pgr} increases—and the potential for gas interference worsens due to the higher compression required to admit fluid into the tbg. Good gas separation and longer SL's can mitigate this problem.

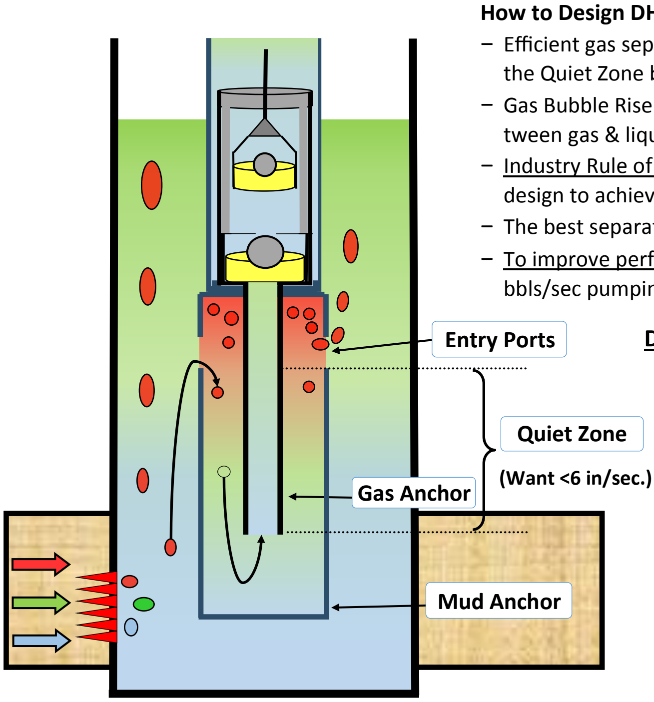
Downhole Gas Separator (DHGS):

How to Avoid Gas Interference:

1. Design the DHGS (and its placement) so that gas naturally bypasses the Fluid Entry Ports on the Mud Anchor.
   - Best achieved by sumping the pump. If pumping above perfs, it *might* be beneficial to **decentralize** the DHGS (set the TAC 2-4 jts above SN), & since no well is 100% 'vertical': the gas will ride the high side while the DHGS (& liquid) occupy the low side.
2. Design the DHGS so the downward fluid velocity is slower than the Gas Bubble Rise Velocity: allowing the gas to escape.
3. If the gas cannot be adequately removed look to install a specialty pump that is better equipped to "pass gas".
   - Managing gas: close pump spacing & long SL; hold more TP (to prevent gas from heading the top of the tbg dry).
4. Sand-Screens or other frictional restrictions can strain the gas out of solution leading to gas interference.
5. In certain situations (depending on the producing zones, TAC placement, & more), the TAC—in conjunction w/ a column of fluid (providing back-P.)—can bottle up high-pressure gas below the anchor leading to severe gas interference.



Decentralized DHGS: when a crooked hole has its benefits.



How to Design DHGS:

- Efficient gas separation requires that the **downward fluid velocity** in the Quiet Zone be **less** than the **gas bubble rise velocity**.
- Gas Bubble Rise Velocity occurs due to the density difference between gas & liquid and is proportional to the diameter of the bubble.
- Industry Rule of Thumb: a 1/4" gas bubble rises at 6 inch/sec. Thus, design to achieve a fluid velocity **<6 in/sec** (& the *slower the better*).
- The best separation can be achieved by sumping the pump.
- To improve performance: increase X-Sec Area & reduce the bbls/sec pumping rate (compensate by increasing run-time).

	OD	ID
GA: Gas Anchor (always listed by ID[+])		
3/4" GA	1.05	0.82
1" GA	1.315	1.05
1-1/4" GA	1.66	1.38
1-1/2" GA	1.90	1.61
MA: Mud Anchors ("Mother Hubbard")		
2-3/8" 4.7#	2.375	1.995
2-7/8" 6.5#	2.875	2.441
3-1/2" 9.3#	3.5	2.922
Casing as ID of Mud Anchor		
4-1/2" 11.6#	4.5	4.000
5-1/2" 17#	5.5	4.892
7" 26#	7	6.276

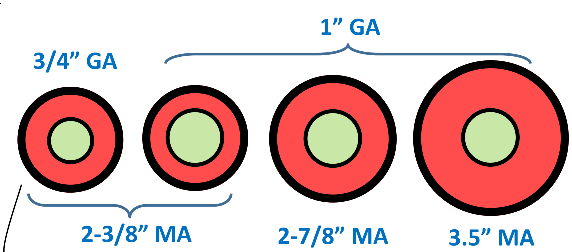
[+]GA: API Line Pipe (standard weight).

Downward Fluid Velocity in DHGS:

$$\vec{V}_{fluid} = \frac{d_p^{\,2} \times SL_{DH} \times SPM}{60 \times \left(ID_{MA}^{\,2} - OD_{GA}^{\,2}\right)}$$

Comparison of X-Sectional Area

(drawn to proportion)

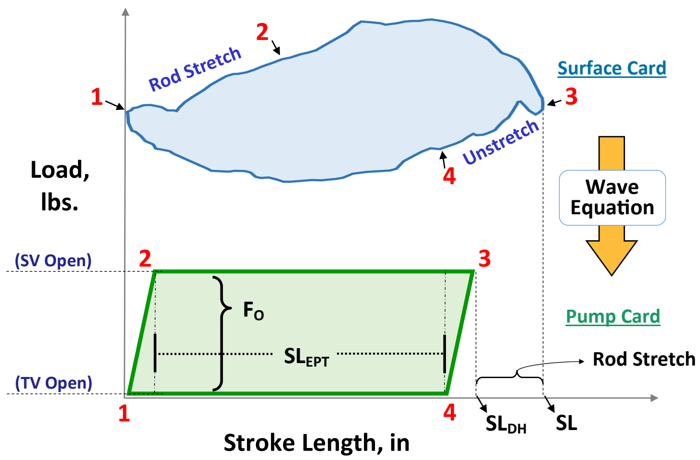


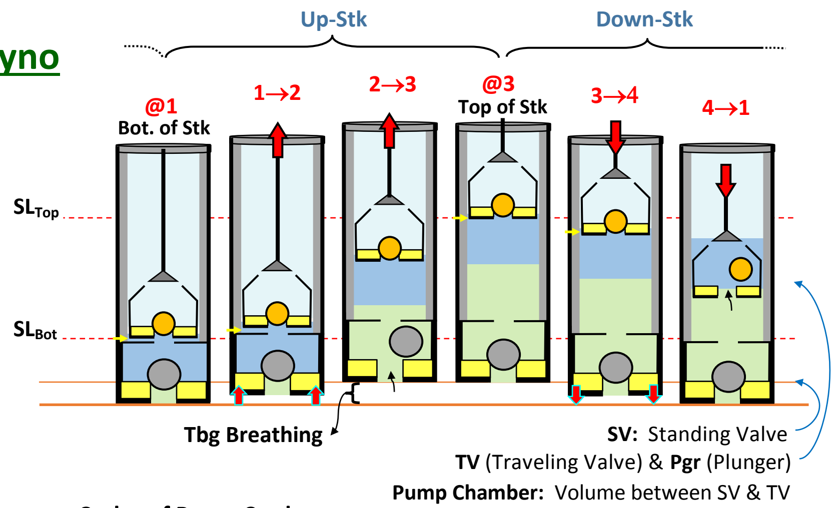
Area of Quiet Zone, in^2: 2.3 1.8 3.3 5.4

Sumped Pump (with 1" GA in Csg), in^2: 11.2 (in 4-1/2" Csg); 17.4 (in 5-1/2" Csg)

www.DownholeDiagnostic.com

Pump & Dyno





Example Well: 10,000' well w/ 50% FG Rods with 2000' of Un-Anchored Tbg (slants pump card).

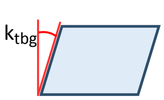
Dynamometer (Dyno) Cards:

- **Surface Card**: displays the load on the Polished Rod (PR) over a pump cycle. The card shape is a function of everything (PPU geometry, SPM x SL, pump depth, rod string design and elasticity, fluid load on pump, etc).
- **Wave Equation**: mathematically models the elastic nature of the rod string (assuming a downhole friction factor), & allows the Surface Card data to be converted to represent what is happening at the pump plunger. A more simplified—but absolutely ***free***—Rod Design Predictive Program solving the Wave EQ is Echometer's **QRod** & can be downloaded at www.echometer.com.
- **Pump Card**: displays the fluid load on the pump plunger (F_O) over a pump cycle. The size and shape of the card indicate the operating conditions and performance of the pump.
  - **SL_{EPT}**: **Effective Pgr Travel** (the ***only*** part that contributes to moving fluid). Only occurs when one valve is open and the other is closed (see the pump cards below for additional examples).
  - **SL_{DH}**: total downhole plunger stroke-length (relative to the csg).

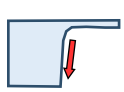
$$SL_{DH} = SL - Stretch_{Rods} + OverTravel$$

Interpreting Pump Card Shapes:

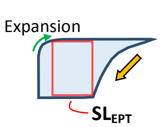
Ideal Card: fully anchored tbg, 100% liquid fillage, & pump in good condition.



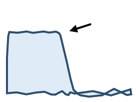
Slanted: Unanchored tbg indicated by the card being slanted at the k_{tbg} (Tubing Spring Constant).



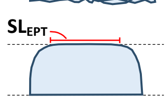
Fluid Pound: sudden impact load. Inefficient and very damaging to pump, rods, tubing, and GBox. The impact load causes rod buckling & rod-on-tbg slap.



Gas Interference (or Gas Pound): a more gradual load transfer as gas compresses (pneumatic cushioning). Greatly reduces the pumping efficiency and indicates the well is not pumped off (≈Fluid# @ a higher PIP).



Hole In Barrel: as the bottom of the plunger passes the hole (arrow) the hydrostatic pressure is equalized across the plunger causing the F_O to be lost.

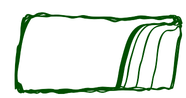


Worn Pump: slow to pick up & quick to release the fluid load, due to: TV leaking or plunger/barrel wear.

Cycles of Pump Card:

- **@1**: **Bottom of Stroke**: Both valves initially closed.
- **#1-2**: Expansion: Pgr moves up picking up the fluid load, F_O. As F_O transfers from tbg to rods, the tbg un-stretches & moves with the Pgr. Unanchored tbg, excessive slippage or gas expansion increase this stage.
- **#2-3**: Intake: SV opens @ **#2** to admit new fluid. Now: rods carry the full F_O.
- **@3**: **Top of Stroke**: SV closes as Pgr stops vacating the chamber.
- **#3-4**: Compression: Pgr begins down. As F_O transfers from rods to tbg the unanchored tbg stretches. TV opens @ **#4** when $P_{Chamber}$ > PDP.
- **#4-1**: Discharge: Pgr moves through the fluid to repeat the cycle.

The 3 Causes of Incomplete Pump Fillage:



1. **Pumped Off**: Pump Capacity > Reservoir Inflow.
2. **Gas Interference**: gas compressibility interfering with the normal actuation of the SV & TV.
3. **Choked Pump**: restricted inflow to pump (plugged sand-screen or excessively high fluid friction).

Compression Ratio of the Pump:

- Anything that increases the compression ratio improves the pump's ability to compress the fluid in the pump chamber & *minimizes* the percentage of the downhole stroke lost to gas compression.
- Longer SL's dramatically help, but minimizing the Unswept Volume is the most crucial & is achieved by: **close pump spacing** along with good pump design (type of pump, high-compression cages, etc.).

$$Comp\ Ratio = \frac{Swept\ +\ Unswept\ Volume}{Unswept\ Volume} = \frac{Vol\ (@\ Top\ of\ Stk)}{Vol\ (@\ Bot\ of\ Stk)}$$

Pump Card Interpretation:

1) The Pump Card **only represents** the load on the plunger$^{\psi}$: so no rod stretch or anything above the plunger is displayed on it.
2) The card shape indicates how the plunger picks up, holds, and releases the fluid load each stroke.
3) Keep in Mind: the TV & SV are **one-way check valves** & they only open when the pressure below becomes greater than the pressure above.
4) *The key to interpretation*:
   The card shape depends only on how the pressure changes inside the pump barrel relative to the plunger movement.
   - A slow load loss on the down-stk indicates the gradual release of F_O: due to gas compression or tubing breathing.
   - A sudden loss on the down-stk indicates fluid-pound as the load transfers almost instantly as the plunger belly-flops into the fluid.
   - On up-stk, a gradual load pick-up indicates the pump's Chamber-P. is **not** *quickly* dropping to PIP, indicating: tbg movement (unanchored), fluid slippage (worn pump), or gas expansion—or all 3 combined.

$^{\psi}$Note: except for DH friction assumptions, this is true for a horseshoe or donut **load-cell** (installed between the Bridle & PR Clamp). For many reasons, most Dyno's commonly used by Well Techs are the quick-install **PRT Dyno** (Polished Rod Transducer) that measures the radial strain (change in diameter) of the PR each stroke & uses this data to back-calculate the F_O—& these Pump Cards can *sometimes* be slightly tilted due to surface misalignment & bending of the PR.

Sucker RP Equipment Design: Considerations

Equipment Design:

- The pumping system should be designed for the long-haul.
- Don't overdesign. If the well is expected to pump-off in 9-months—at which point the production can be maintained with a slower SPM & downsized pump (decreasing the loadings)—great savings can be incurred by temporarily (fully) taxing a smaller GBox or Grd D Rods (vs HS Rods) for those 9-months instead of upsizing.
- **Longer SL's and slower SPM is preferable**. Advantages include:
  - With a Longer SL: Rod-stretch, gas compression, or unanchored tbg breathing will consume a *smaller percentage* of each stroke.
  - Long SL's *increase* the compression ratio & the ability to pump gas, & require *fewer* down-stks **{**rod buckling**}** to achieve the same prod.
  - Slow SPM reduces: buckling tendencies & rod-on-tbg wear, rod loadings & the impact force of the plunger if it does #Fluid or tag.

Rod Design:

Sucker Rods are designed to *only* be operated in tension (hence K-bars). Rods operate in a *pulsating tension* along each stroke as the F_O is picked up & released—& as a result of the stress reversal cycles—they have a limited run life. The **API Modified Goodman Diagram** (MGD) is the industry design guide that that attempts to quantify a rod's estimated run life based on the Max & Min stress loadings the rod will experience under the operating conditions. Using this guide, rod loadings are reported as "Percentage of Goodman". In a noncorrosive environment, a **steel rod** operating at 100% MGD Loading is expected to have a run-life *greater* than 10×10^6 cycles [or 10 SPM pumping for ~2 years), while **FG rods** @ 100% MDG have an expected >7.5×10^6 cycles @ 160°F. As the MGD loading decreases below 100%, the run-life increases *exponentially*. Since the MGD loading value does not take into account corrosion [or buckling, mishandling damage, etc.] the MGD run-life must then be de-rated by a Service Factor+ related to the corrosivity of the downhole environment.

Fiberglass Rods: (AKA, **FRP Rods: F**iber **R**einforced **P**lastic)

- Weigh 70% less & are 4× more elastic than steel, are corrosion resistant (**not** de-rated for corrosive environments), have an undersize pin (allowing 1" FG rods to be used in 2-3/8" tbg, etc.) & have mechanical strengths comparable to HS-steel rods. Their expected run-life if temperature dependent.
- FG elasticity is advantageous for fast pumping wells with high fluid levels (leads to plunger Over-Travel). Their elasticity is **dis**advantageous for slower pumping wells with large F_O (SL_{DH} is lost to rod-stretch). This is why on pumped-off FG wells, downsizing the pump *often* does not substantially reduce production: the *downsized* d_p *increases* the DH_{SL} (due to smaller F_O).

Steel Rods:

- Rod Grades (**C**, **K**, **D**, & **HS**): selection should be made based on the mechanical loadings on each taper and the downhole corrosivity.
- Grd D rods: **DC** (carbon), **DA** (alloy), & **DS** (special).
- Different heat treating processes create different mechanical properties. Generally, as rod strength is increased the rod becomes more susceptible to corrosive attack & mishandling damage (nicks & dings that cause *Stress Risers* & become the nucleation point for future corrosive attack).
- Sinker Bars: are designed to absorb the DH compressive forces & keep the other rods in tension. Their larger OD distributes side-loads from buckling forces over a larger area—so they do not cut as incisively into the tubing.

Rod Boxes: (AKA: **Rotary-Connected, Shoulder-Friction-Held Connections**)

- The make-up torque (checked by Circumferential Displacement) puts tension in the rod pin and friction locks the box to the face of the pin shoulder. This pre-stress put into the connection must be greater than the up-stk dynamic rod load which attempts to pull the connection apart.

Pump:

- Tbg Pumps: largest bore pumps (d_{Pgr} just a 1/4" < ID of tbg).
- Rod (Insert) Pumps, 3-types: based on where the hold-down is located (top or bottom) & whether the barrel is Stationary or Traveling.
- First efforts should be made to exclude gas & solids from entering the pump *before* resorting to a pump design that attempts to accommodate them.
- A favorite pump of ours is the **2S-HVR** (2-Stage Hollow Valve Rod). The upper TV (on the HVR) holds back the hydrostatic pressure allowing the lower TV to more easily open when pumping gaseous fluids. It also distributes fluid discharge across the whole SL (*greatly* minimizing Pump Discharge Leaks), & the *hollow* valve rod is more stiff & less inclined to buckle.

Tubing & TAC: (**T**ubing **A**nchor **C**atcher)

- Unless anchored with pre-tension, the tubing will stretch and contract each stroke as the rods pick up & release F_O. This "breathing" decreases the pumping efficiency because *only* the **net relative movement** of the plunger to the pump barrel contributes to fluid displacement.
- With **un**anchored tbg: on the down-stk, as the rods start down & begin to release the F_O (onto the tbg) the tbg stretches accordingly. On the up stk, the tbg recoils & helically buckles [wrapping around the stretched rods] causing the pump barrel to initially move upward w/ the plunger.
- Smaller diameter pumps will cause *less* tbg breathing. In a pumped off 8000' well with 2-3/8" tbg: 1-1/16" pump (**7.5"**) vs 1-1/2" pump (**15"**).
- Eq. for **Tbg Stretch** or to calculate the **Depth to Free-Point** (stuck pipe):

$$Tbg\ Stretch = k_{tbg} \times L_{tbg} \times F_{Pull} \qquad k_{tbg} = 0.4 / A_{tbg,\text{x-sec}}$$

  - **Note**: Stretch (inches); L_{tbg} (in 1000's of ft); F_{Pull} (1000's of #'s).
  - k_{tbg} = Stretch Constant: is *not* affected by the grade of steel, only the x-sec area (given on p.5 or use above equation).
  - L_{tbg} = Length of tbg being stretched by the force, F_{Pull}.
- Proper TAC Setting Procedure: after 8 left-hand turns (or until it torques up) continue to hold the torque as the operator alternates 10 pts tension & compression before releasing the pipe wrenches (this works the torque downhole & **fully** engages the TAC slips so it will not turn loose).

+Generally Accepted Service Factors for Sucker Rods:

Environment	Grd C	Grd K	Grd D	HS Rods
Non-Corrosive	1.00	1.00	1.00	1.00
Salt Water	0.65	0.90	0.90	0.70
H2S	0.45	0.70	0.65	0.50

High-Strength Rods: due to their heightened susceptibility to corrosion, many rod pumping gurus recommend loading Grd D rods up to 100% MGD Loading (using a 1.0 Service Factor) *before* resorting to the use HS rods.

Load on the Polished Rod (PR):

$$F_{PR,Up-Stk} = W_{rf} + F_O + F_{Dynamic/\text{friction}}$$

$$F_{PR,\text{Down}-Stk} = W_{rf} - F_{Dynamic/\text{friction}}$$

- W_{rf} = Weight of rods in fluid (compared to W_r: weight of rods in air).
- In fresh water, **FG rods** weigh 58% of W_r & **steel rods** = 87% of W_r.
- Dynamic Loads: result from PPU kinematics & acceleration forces.
- Friction Loads: result from rod-on-tbg engagement, fluid friction ("viscous drag"), paraffin sticking, stuffing box friction, & pump friction (AKA "plunger drag").
- Proper Counter-Weight Balance requires balancing the **average** load on the Polished Rod, thus: $$CW\ Bal = W_{rf} + 0.5 \times F_O$$

Laboratory Measured Loads to Buckle Rods:

- Test conducted with rods in air (Long & Bennett, 1996).
- Notice the large difference even between the 3/4" and 7/8" rods.

Rod Diam.	Force to Buckle
3/4	23#
7/8	162#
1 3/8	641#

Equation for FG Rod Spacing: Inches Off Bottom

$$FG\ Spacing = \frac{9 \times h_{FG\_Rod}}{1{,}000} + \frac{2 \times h_{SN}}{1{,}000}$$

- Space 9" for every 1000' of FG Rods & 2" for every 1000' to SN.
- Slow stroking units can space closer than the calculated inches.
- For proper pump spacing (*especially* w/ FG rods due to their elasticity), load the tbg with fluid *prior* to spacing the pump out.

SRP Optimization

Design Considerations:

- On 1.5” K-bars, run 3/4” **SH**-boxes (1.5” OD) *instead* of FH-boxes. This creates a uniform diameter over the bar section & spreads out any side loading on the tbg over a larger area, minimizing stress (Stress = F/Area).
- Install boronized (EndurAlloy) tbg or Poly-Lined tbg in bottommost jts where most tbg leaks occur.
- Spray Metal Boxes: corrosion resistant and made for highly erosive/ corrosive environments. The SM coating is more abrasive on the tbg because the tbg will wear down before the box does (as opposed to **T**-boxes where the protruding edge will wear out & conform to the tbg ID).

Pulling the Well:

- Create a Pre-Pull Plan: review location of recent failures, latest well tests, and FL/Dyno reports to see if DH equipment should be modified.
- On 1st tbg failure, scan the tbg out of hole: to get an initial *rod wear profile* on the new tbg, & to check chemical program (pitting).
- During a tbg job: rotate ~10 jts of “fresh” tbg from top to bottom.
- During a rod job: can rotate a steel pony rod (≥ SL) to bottom. This shifts all the boxes up out of their existing wear tracks to rub on fresh tbg.
- Root-Cause Failure Analysis: *Identify the cause!* Clean corrosion deposits off with a wire brush/diesel, cut failed tbg jts open, discuss with Chemical Co. & take pictures to include in the pull report for future reference.

Operations & Monitoring:

- **Stroke her long & stroke her slow—and match her inflow**.
- Keep the pump barrel full. Ensure proper run-time by calibrating it with a FL Shot/Dyno Survey, a POC, well tests, or by hiring a *good* pumper.
- As the well pumps off, reduce the SPM: this improves run-life, improves downhole gas separation, & is **insurance** by **reducing the force of impact** generated if (*or* when) the plunger pounds fluid or tags.
- Mix in biocide with any fluids introduced into the well. Bacterial pitting can be the most aggressive in drilling holes in your rods & tbg (…& csg!)

Fluid Level Gun & Dyno:

- **Fluid Level** & **Dyno** Surveys are noninvasive diagnostic tools that quantify the well’s ***Producing Performance***—in terms of the well’s Production Potential* (reservoir drawdown) & the Operational Lifting Efficiency of the rod pumping system (how efficiently the fluid is being lifted to surface).
- By interpreting the diagnostic data in context of the well, producing inefficiencies can be detected & corrected. The diagnostic data **lays the foundation** from which **prudent operational decisions** can be made & justified.
- **Dyno’s**: measure rod/pump performance (see *Pump & Dyno* page).
- **Fluid Level Gun**: generates an *acoustic wave* (pressure pulse) that travels down the well, reflects off cross-sectional changes in area (collars, perfs, TAC) until the wave encounters the fluid level & completely reflects back.
- The gun’s internal microphone records the amplitude and polarity of the reflections on an **Acoustic Trace** and allows the depth to the top of the Gaseous Fluid Level to be determined.
- The subsequent Casing Pressure Build-Up Test allows for the quantification of the MCFPD of gas producing up the casing and, consequentially, allows for the determination of the **GFLAP** (Gas Free Liquid Above Pump) and **BHP’s** (Bottom Hole Pressures), like: ***PIP***, ***PBHP***, & ***SBHP***.
- **Polarity of Acoustic Reflections**:
  - ↑**kick**: **Opening** in Cross-Sec Area (negative reflection—“Rarefaction”)
  - ↓**kick**: **Restriction** in Cross-Sectional Area (positive reflection).

Objectives of Rod Pumping Optimization:

Fully achieve the well’s maximum producing potential with minimum expenditure (*including* time & attention).

How RP Optimization is Achieved:

1) **Good Equipment Design:** rod/pump/PPU design, gas separation, SPM x SL, metallurgy, SN placement.
2) **Match:** Pump Capacity ≈ Reservoir Inflow.
3) **Operations:** Avoid Fluid#, Gas#, & Pump Tagging.
4) **Chemical Program:** Both active and **re**active.
5) **Inspiration:** Field hands must buy into the program.

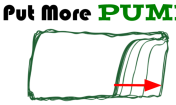
Changing PPU SPM:

$$SPM_{New} = SPM_1 \frac{d_{New}}{d_1}$$

Frame Size	Shaft Diam
143T, 215T	1-3/8"
254T, 256T	1-5/8"
284T, 286T	1-7/8"
324T, 326T	2-1/8"
364T, 365T	2-3/8"
404T, 405T	2-7/8"
444T, 445T	3-3/8"

- To change the SPM the existing motor sheave size (d_1) & the motor shaft diameter (measured or correlated with Frame Size on motor) must be known.
- Drive belts sit ~4/10” within the sheave OD, thus a measured 7.4” sheave OD is really a 7” sheave.
- For an expanded list of frame sizes: **www.downholediagnostic.com**
- The smallest sheave size is 5”. If the desired SPM would require a sheave size smaller than 5” look into: upsizing the Bull sheave (on GBox), install a **jack-shaft** or a **VFD** (Variable Frequency Drive), or consider shortening the SL. FYI: “sheave” is pronounced “shiv”.

Gas Interference (or “Gas Pound”) & Fluid Pound:

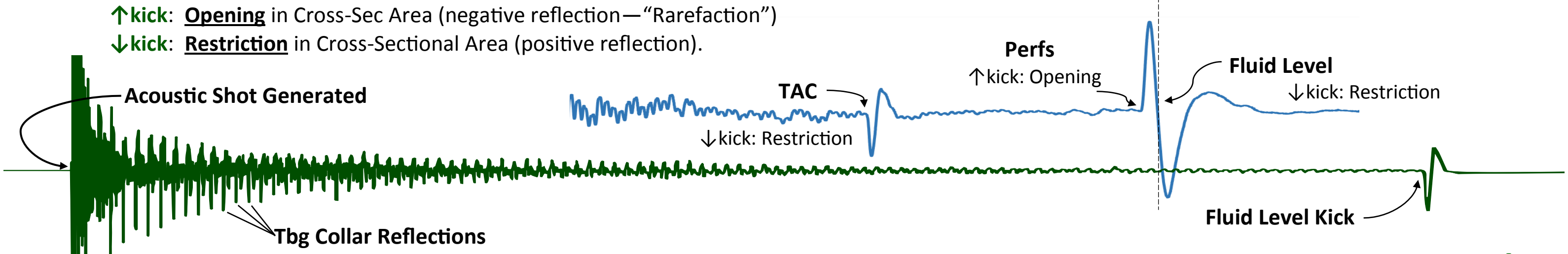


- Gas Pound is essentially Fluid Pound but at a higher PIP & with more compressible gas in the pump. Gas# is *just as inefficient* as Fluid# but—due the cushioning effect of the gas—it is less destructive to the downhole equipment.
- Although less damaging, wells experiencing gas interference are **not** achieving maximum production due to the additional fluid column that cannot be pumped down. **At least with Fluid#**: you know your getting ALL the production (& *trying* to get some more:)
- Pounding is a shock loading that induces the rods to helically buckle as they bow out and engage the tbg walls. The **force of the impact** is proportional to: F_O (thus d_P^2), the velocity of the plunger at the time of impact, and the time duration for the load transfer to occur.
- Gas or Fluid# in the **middle of the down-stk** can be much more damaging because here the plunger is at *peak* downward velocity.
- Fluid# can often be detected by listening for GBox “thuds,” motor speed changes, & watching for the bridle/Polished Rod to twitch on the down-stk . However, for slower SPM or FG rod-strings it can be more difficult to identify without the aid of a Dynamometer analysis.

* Vogel’s IPR (Inflow Performance Relationship):

Well’s Reservoir Producing Efficiency (ratio); WT: Well Test

$$\frac{q_{WT}}{q_{max}} = \left[1 - 0.2\frac{PBHP_{WT}}{\overline{P}} - 0.8\left(\frac{PBHP_{WT}}{\overline{P}}\right)^2\right] \quad \left(\overline{P} = SBHP\right)$$



Downhole Diagnostic

Rod, Tbg & Csg Specs

In general, the API minimum standards are listed on this page for the most common grades of pipe used in the **Permian Basin**. Individual products from manufacturers might exceed some of the listed mechanical properties. Consult the manufacturer for specifics & use a **Safety Factor** to de-rate used rods/tbg.

	Diam in	Wt in Air lb/ft[ψ]	X-Sec Area, in^2	Diam of Coupling: Slim Hole OD, in	Diam of Coupling: Full Hole OD, in	(Stuck Pump) Grd D Rods [θ]Max Short Term Pull, lbs
Steel Rods	5/8”	1.11	0.307	1 1/4	1 1/2	24,500
	3/4”	1.63	0.442	1 1/2	1 5/8	35,500
	7/8”	2.22	0.601	1 5/8	1 13/16	48,000
	1”	2.90	0.785	2	2 3/16	63,000
	1 1/8”	3.68	0.994	2 1/4	2 3/8	80,500
				Pin Size		
Sinker Bars	1 1/4”	4.17	1.227	**5/8 or 3/4**		Not usually a concern.
	1 3/8”	5.00	1.485	**5/8 or 3/4**	/	
	1 1/2”	6.00	1.767	**3/4 or 7/8**	/	
	1 5/8”	7.00	2.074	**7/8**	/	
	1 3/4”	8.20	2.405	**7/8**	/	*FG Max Short Term Pull[MS]
				Pin Size		
FG Rods	3/4”	0.53[MS]	0.424[MS]	**3/4**	Match Pin Size to steel rod diameter for available box sizes.	**20 - 21**,000
	7/8”	0.65[MS]	0.578[MS]	**3/4**		**25 - 29**,000
	1”	0.88[MS]	0.760[MS]	**7/8**		**35 - 41**,000
	1 1/4”	1.38[MS]	1.200[MS]	**1**		**50 - 60**,000

[ψ]Weight of couplings not included. The **lb./box** (Full Hole) goes from: **1.3#** (5/8”) → **3.1#** (1-1/8”).
[θ]Max Pull for new rods based on a smooth pull (**not** herky-jerky). The load pulled at the top of each taper must be computed and the pull should not exceed the lowest limit. De-rate w/ a S.F.
[MS] **Manufacturer Specific**: **average values given** (except the FG max pull shows the range between the 3-primary manufacturers). Max Pull on **FG Rods** is limited by the end-fitting connection.

Rod Grade	Min Yield Strength, psi	Min Tensile Strength, psi	AISI Designation
Grd C	60,000	90,000	C-1536-M
Grd K	60,000	90,000	A-4621-M
Grd D	85,000	115,000	A-4630-M
HS Rods	115,000	140,000	A-4330-MI
FG Rods	90,000	115,000	/

Min. Yield Strength: the max stress the rod can bear before yielding (i.e. before the stress crosses over from **elastic stretch** to **plastic deformation**). Beyond this stress the material is permanently elongated! (use for max stress calcs.)

Min. Tensile Strength, T_{Min}: the stress that will cause the material to pull into 2-pieces. Depending on the Max & Min stress fluctuation experienced by a rod during the pumping cycle the **100% MGD Loading** resides between 25-56% of T_{Min}. As the min. stress on the down-stk *approaches* buckling (zero load), 100% MGD = 25% of T_{Min}.

$$Stress = \frac{Force}{Area} \qquad Strain = \frac{\Delta L}{L} = \%Elongation$$

	Diam in	Weight #/ft	Metal X-Sec Area, in^2	ID in.	Drift in.	OD of EUE Collar, in.	Capacity bbls/ft	Capacity [+]ft/bbl	Displacement *bbls/ft	k_{tbg}, Stretch Constant
Tbg (EUE)	**2 1/16”**	**3.25#**	0.933	1.751	1.657	na	**0.00298**	336	0.00116	0.42781
	2 3/8”	**4.7#**	1.304	1.995	1.901	3.063	**0.00387**	258	0.00167	0.30675
	2 7/8”	**6.5#**	1.812	2.441	2.347	3.668	**0.00579**	173	0.00232	0.22075
	3 1/2”	**9.3#**	2.590	2.992	2.867	4.500	**0.00870**	115	0.00334	0.15444
Csg	**4 1/2”**	**11.6#**	3.338	4.000	3.875	5.00	**0.0155**	64	/	0.11983
	5 1/2”	**15.5#**	4.514	4.950	4.825	6.05	**0.0238**	42	/	0.08861
	"	**17#**	4.962	4.892	4.767	"	**0.0232**	43	/	0.08061
	"	**20#**	5.828	4.778	4.653	"	**0.0222**	45	/	0.06863
	7”	**26#**	7.549	6.276	6.151	7.656	**0.0383**	26	/	0.05299
	"	**29#**	8.449	6.184	6.059	"	**0.0371**	27	/	0.04734

[+]Note: ft/bbl has been rounded. *Displacement (bbls/ft) for EUE open-ended tbg (includes the disp. volume of upsets & couplings).

Tbg Joint Yield Strength Calc:

Ex: **2-3/8” 4.7# N-80**

X-Sec Area = 1.304 in^2

Min Yield = **80**,000 lb/in^2

$$80{,}000 = \frac{Force}{1.304}$$

Thus, the Min. Force to Yield the New Tbg = 104,320#.

Used Tbg, API Bands

Color Band	Body Wall Loss
White	Brand New
Yellow	0-15%
Blue	16-30%
Green	31-50%
Red	51-100%

Mechanical Properties of EUE (External Upset End) Tbg:

Tbg Size	Weight #/ft	Grade	Collapse Pressure, psi	Burst Pressure, psi	Max Pull to Yield, Lbs.	MakeUp Torq. (optim.), ft-lb
2 3/8”	**4.7#**	J-55	8,100	7,700	71,730	1290
	"	L/N-80	11,780	11,200	104,340	1800
	"	P-110	13,800	15,400	143,470	2380
2 7/8”	**6.5#**	J-55	7,680	7,260	99,660	1650
	"	L/N-80	11,160	10,570	144,960	2300
	"	P-110	13,080	14,530	199,320	3040

Tubing API Grade: **“Letter Grade”—“Min. Yield Strength (in 1000’s of psi)”**
(Different heat treating processes & alloys combine to create the higher strength grades)

Buoyancy Force: is equal to the weight of the fluid displaced by the immersed object.

- ρ_{steel} = 489 lb_m/ft^3 & $\rho_{Fiberglass}$ = 150 lb_m/ft^3.
- In Fresh Wtr (SG=1.0): FG weighs 58% & Steel 87% the W_{Air}.

$$\frac{W_{Buoyant}}{W_{Air}} = \left(1 - \frac{62.4 \times SG_{O/W}}{\rho_{Material}}\right) \quad \text{(weight ratio)}$$

Capacity Factor (CF): for *any* size hole *or* annulus (in bbls/ft)

- Set OD = 0” if no concentric string is inside the pipe.
- Ex: ignoring upsets/boxes, the C.F. between 2-3/8” tbg (ID=1.995”) & a string of 3/4” rods (OD=.75”) is 0.00332 bbls/ft.

$$CF = \frac{ID^2 - OD^2}{1029}$$

Capacity	Tbg Size	4-1/2" 10.5# bbls/ft	4-1/2" 10.5# ft/bbl	4-1/2" 11.6# bbls/ft	4-1/2" 11.6# ft/bbl	5-1/2" 15.5# bbls/ft	5-1/2" 15.5# ft/bbl	5-1/2" 17# bbls/ft	5-1/2" 17# ft/bbl	5-1/2" 20# bbls/ft	5-1/2" 20# ft/bbl	7" 26# bbls/ft	7" 26# ft/bbl	7" 29# bbls/ft	7" 29# ft/bbl
Tbg/Csg Annulus	2-3/8"	0.0105	96	0.0101	99	0.0183	55	0.0178	56	0.0167	60	0.0328	31	0.0317	32
	2-7/8"	0.0079	126	0.0075	133	0.0158	63	0.0152	66	0.0141	71	0.0302	33	0.0291	34
Tbg/Csg Annulus + Tbg Capacity	2-3/8" 4.7#	0.0144	70	0.0140	72	0.0222	45	0.0217	46	0.0206	49	0.0367	27	0.0355	28
	2-7/8" 5.6#	0.0137	73	0.0133	75	0.0216	46	0.0210	48	0.0199	50	0.0360	28	0.0349	29

***Note**: ft/bbl has been rounded to aid memory.

Nomenclature, API, & EQ's

API Pumping Unit (PPU) Description:

C 320 D — 305 — 100
a $\#_1$ b

- **Max SL**, in.
- **PPU Structure Rating**, 100's of lbs.

a: PPU Type:

- C: Crank Balanced
- B: Beam Balanced
- RM: Reverse Mark
- A: Air Balanced
- M: Mark II (grasshoppa)

$\#_1$: **GBox Torque**, 1000's of in-lbs.

b: **D** - Double Reduction GBox

Note: PPU's that have the Equalizer Bearing residing directly over the GBox Crankshaft will use equal degrees of crank rotation for both the up & down-stroke. The equalizer bearing is shifted forward towards the horse head on the Reverse Mark & Mark II making their **up-stk 12% (RM) & 18% (MII) slower than their down-stk**.

Nomenclature:

< *or* >	Less than *or* Greater than. Ex: 1 < 1.01; **A&M** > **UT**
Δ	Delta, represents the *change* in a quantity
%	Percentage (use a fraction: 25% = 0.25)
ε	Efficiency, fraction (85% = 0.85)
ρ	Density, lb./ft^3 (wtr = 62.4 lb/ft^3)
μ	Viscosity of Fluid, cp ↑ *Math & Greek*
A	Area, in^2
API	American Petroleum Institute, industry guidelines
d	Diameter, in.
BFPD	Bbls Fluid Per Day (i.e. Oil+Wtr: BOPD + BWPD)
BHP	Bottom Hole Pressure, psi
CP	Csg Pressure (usually Flowline P.), psi
DH	Downhole (abbrev.)
DHGS	Downhole Gas Separator/Separation
F	Force, lb.
F_O	Fluid Load on Pump, lb.
GA	Gas Anchor: inner tube of DHGS
GFLAP	Gas Free Liquid Above Pump, ft.
h	Height, ft
ID	Internal Diameter, in.
k	Spring Constant, units: in./1000 lb./1000 ft
L	Length, ft. (unless noted)
MGD	Modified Goodman Diagram (% rod loadings)
OD	Outer Diameter, in.
P	Pressure, psi
PBHP	Producing BHP (@ bottom perf), psi
Pgr	Plunger
PIP	Pump Intake Pressure, psi
PDP	Pump Displacement Pressure, psi
ppg	Pounds per Gallon, Lb./gal (Brine = 10 ppg)
PPU	Pumping Unit (AKA Pumpjack, Nodding Donkey)
PPM	Parts Per Million
PR	Polished Rod (top connecting rod)
SBHP	Static BHP (local avg. Reservoir P.), psi
SG	Specific Gravity (FW = 1.0 SG = 8.34 ppg)
SL	Stroke Length, in
SPM	Strokes Per Minute, stk/min
SV	Standing Valve (pump's non-moving valve)
tbg	Tubing (abbrev.)
TAC	Tubing Anchor Catcher (for tbg tension)
TV	Traveling Valve (moving/stroking valve of pump)
TVD	True Vertical Depth (vs Measured Depth), ft
TP	Tubing Pressure, psi
W	Weight, lb.

Subscripts:

D,FL	Dead Fluid Level (FL when gas volume subtracted)
DH	Downhole (e.g. @ the pump)
DT	Dip Tube: inner barrel of DHGS
EPT	Effective Pgr Travel ("pumping" part of DH SL)
FG_Rods	Length of Fiberglass Rods, ft.
FL	Fluid Level (the "kick" on the Acoustic FL Trace)
MA	Mud Anchor: outer barrel of DHGS
p	Pump
O *or* W	Oil *or* Water; O/W = Oil & Wtr (mixture)
rf	Rods in Fluid (considering buoyancy force)
RT	Run Time, fraction of the day the well pumps
SN	Seating Nipple (i.e. pump depth)
tbg,x-sec	Cross sectional metal of tbg

API Pump Designation:

20—125 R H B C 20—5—4—0
$\#_1$ $\#_2$ a b c d $\#_3$ $\#_4$ $\#_5$ $\#_6$

- $\#_1$: Tubing Size, ID - 20 = 2.0" (2-3/8"); 25 (2-7/8"); 30 (3.5")
- $\#_2$: Pump Bore, ID - 125 = 1.25", etc.
- a: Pump Type: **R**: Rod, **T**: Tbg
- b: Plunger Type & Barrel Thickness:
  - Metal Pgr: **H**: Heavy, **W**: Thin
  - Soft Pgr: **P**: Heavy, **S**: Thin
- c: Seating Assembly Location: **A**: Top, **B**: Bottom, **T**: Bot. (Traveling-Barrel)
- d: Seating Assembly Type: **C**: Cup, **M**: Mechanical
- $\#_3$: Barrel Length, ft.
- $\#_4$: Plunger Length, ft.
- $\#_5$: Length of Upper Extension, ft.
- $\#_6$: Length of Lower Extension, ft.

Also important to know:
Plunger & Barrel Metallurgy, Plunger Clearance ("Fit"), & the Valve Metallurgy.

Helpful Reference EQ's:

°API	S.G.
30	0.88
35	0.85
40	0.83
45	0.80
50	0.78

Chlorides ppm	Density ppg	Specific Gravity
0	8.34	1.00
50,000	8.62	1.03
100,000	8.96	1.07
150,000	9.26	1.11
200,000	9.60	1.15
250,000	9.96	1.19
258,000	10.00	1.20

S.G. of Oil:

$$SG_O = \frac{141.5}{API + 131.5}$$

S.G. of Produced Water:

The SG of produced water is a function of the **TDS** (Total Dissolved Solids), not just Chlorides. So a Wolfberry well producing 100K Cl probably has a S.G. closer to ~1.09.

S.G. of O/G Mixture:

$$SG_{O/W} = \frac{BOPD \times SG_O + BWPD \times SG_W}{BOPD + BWPD} = \%_O \times SG_O + \%_W \times SG_W$$

Assuming gas-free.

Bottom Hole Pressure:

$$BHP = P_{Surface} + 0.433 \times SG \times h_{TVD} = P_{Surface} + 0.052 \times ppg \times h_{TVD}$$

Avg Polished Rod Velocity:

$$\vec{V}_{PR} = \frac{2 \times SL \times SPM}{12} \quad (\text{ft/min})$$

For comparing pumping speeds (velocity) of wells w/ different SL's.

Fluid Slippage:

$$Slippage = [1 + 0.14 \bullet SPM] \times 453 \frac{d_{pgr} \times \Delta P_{pgr} \times C_{pgr}^{1.52}}{L_{pgr} \times \mu} \quad (\text{BFPD})$$

(2006, Patterson Equation)
C_{Pgr}: Total Plunger/Barrel Clearance (inches; "5 Fit" = 0.005")
L_{Pgr}: Pgr Length (inches). μ: fluid viscosity (cp)

Failure Frequency:

$$Failure\ Frequency = \frac{\#\ of\ Failures/Year}{\sum Producing\ Wells}$$

(A F.F. of 0.25 = 4-yr avg Run Life per well)

APB's & SRB's are the oilfield's STD's! Both set-up shop on downhole metallurgy and wreak havoc. **A**cid **P**roducing **B**acteria excrete acids while **S**ulfate **R**educing **B**acteria generate H_2S—which both rapidly corrode the steel. Worse yet, the byproducts of the corroded steel further inhibit the ability of chemicals to penetrate & kill the underlying colonies. **MIC** (Microbial Influenced Corrosion) is highly *penetrating* and can quickly initiate rod parts & tbg leaks. **Protect your producers** by biocide-treating *any* fluids introduced into a well (*including* frac jobs). If introduced into the deepest part of each and every frac stage, there is no possible recourse for their removal from the formation—*only* Hope & Faith remain. **And** if APB's & SRB's are the oilfield STD's—that would make *Pump Trucks* the licentious couriers propagating this most pernicious seed from lease-to-lease, operator-to-operator.

"An ounce of prevention is worth a pound of cure." -Benjamin Franklin

SRB pitting with the characteristic pits-within-pits. All the black splotches are the corrosion byproduct (iron sulfide scale) with colonies residing underneath (center pits cleaned out with wire brush).